TECHNICAL REVIEW DOCUMENT
For
RENEWAL OF OPERATING PERMIT 95OPBO059

University of Colorado at Boulder
Power House
Boulder County
Source ID 0130553

Prepared by Blue Parish
October & November, 2009 & January - February 2010
Updated May & June 2010 to address the proposed NESHAPS for Boilers
Updated August 2010, to address comments from the source received during public notice
Updated September 2010 to address future Greenhouse Gas Requriements

I. Purpose

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit for the Power House. The previous Operating Permit for this facility was originally issued on January 1, 1999 and was last renewed on October 1, 2005.

This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted on October 6, 2009, additional information submitted on January 16, 2009, November 18, 2009 and December 10, 2009 comments on the draft permit submitted on June 14-17, 2010, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant's consultant. Please note that copies of the Technical Review Document for the original permit and previous renewals and any Technical Review Documents associated with subsequent modifications may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

The University of Colorado at Boulder (CU) consists of the Power House, a service building, a heating plant for a dormitory known as Williams Village, and miscellaneous insignificant activities around campus. The Power House is a co-generation plant producing electricity and steam. The Power House has two 16.5 MW turbines with the capability of firing either natural gas or No. 2 fuel oil. The exhaust gasses from the turbines are routed through two duct heaters with each unit having its own stack. The Power House also has two standby boilers which can fire either natural gas or No. 2 fuel oil and serve the purpose of backup steam generators to the heat recovery steam generators. Each backup unit has its own stack. CU requested separate Operating Permits for the Power House and the heating plant for Williams Village. The service building is classified as an insignificant source of emissions.

The Power House is located at the southeast corner of 18th Street and Colorado Avenue, which is approximately in the center of the CU Boulder campus. This facility is located in the Denver Metro Area. The Denver Metro Area is classified as attainment/maintenance for particulate matter less than 10 microns in diameter (PM_{10}) and carbon monoxide (CO). Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Regulation No. 7, Section II.A.1. There are no affected states within 50 miles of the plant. The Federal Class I designated areas within 100 kilometers of the plant are Rocky Mountain National Park, Rawah Wilderness Area, and Eagle's Nest Wilderness Area.

The Power House and the Williams Village heating plant are categorized as a single Non-attainment New Source Review (NANSR) major stationary source (Potential to Emit of $NO_x \geq 100$ Tons/Year). Future modifications at this facility resulting in a significant net emissions increase (see Reg 3, Part D, Sections II.A.26 and 42) for VOC or NO_x or a modification which is major by itself (Potential to Emit of $\geq$ 100 TPY of either VOC or NO_x) may result in the application of the NANSR review requirements.

This facility is categorized as a Prevention of Significant Deterioration (PSD) major stationary source (Potential to Emit > 100 Tons/Year for NO_x, CO and SO_2). Future modifications at this facility resulting in a significant net emissions increase (see Reg 3, Part D, Sections II.A.26 and 42) or a modification which is major by itself (Potential to Emit of $\geq$ 100 TPY) for any pollutant listed in Regulation No. 3, Part D, Section II.A.42 for which the area is in attainment or attainment/maintenance may result in the application of the PSD review requirements

Emissions (in tons/yr) at the Power House are as follows:

Pollutant	Potential to Emit (tpy)	Actual Emissions (tpy)
NOx	Less than 250	232.7
CO	90	41.1
VOC	62.6	3.45
SO_2	56.7	3.45
PM	24.2	8.25
PM_{10}	24.2	8.25
Total Hazardous Air Pollutants (HAPs)	1.2	Not reported
Highest Single HAP (Formaldehyde)	1.0	Not reported

PTE for criteria pollutants are based on permit limits (PM_{10} PTE is assumed to be the same as PM PTE). PTE for HAPs are based on AP-42 factors (see Attachment 1 for details). Actual emissions are as reported to the Division's Inventory system for the year 2009.

Emissions (in tons/yr) for the Power House and Williams Village locations combined are as follows:

Pollutant	TOTAL Potential to Emit (tpy)	Actual Emissions (tpy) – Power House	Actual Emissions (tpy) – Williams Village
NOx	Less than 293	232.7	2.63
CO	117.8	41.1	2.19
VOC	64.4	3.45	0.14
SO_2	103.7	3.45	0.02
PM	32.7	8.25	0.20
PM_{10}	28.4	8.25	0.20
Total Hazardous Air Pollutants (HAPs)	1.3	Not reported	Below APEN Thresholds
Highest Single HAP (Formaldehyde)	1.1	Not reported	Below APEN Thresholds

Actual emissions for Williams Village are from an APEN received on July 27, 2007. See Attachment 1 for details on Williams Village emission calculations.

Applicable Requirements – Williams Village/Power House

Prevention of Significant Deterioration (PSD) Thresholds

The original permit and subsequent renewal noted that the facility was subject to a 250 ton per year major source threshold for PSD applicability. However, EPA has concluded that "the definition of fossil fuel-fired steam electric plants (one of the source categories in 52.21(b)(1)(i)(a) having a 100 tpy rather than a 250 tpy major source emission rate threshold) encompasses gas turbine combined cycle and cogeneration plants."[1]

Because combined potential emissions from the Power House and the Williams Village heating plant exceed 100 tpy each of CO, NO_x and SO_2, the facilities are considered a major stationary source with respect to these pollutants.

<u>Applicable Requirements – Power House</u>

<u>40 CFR 63 - National Emission Standards for Hazardous Air Pollutants</u>

The facility is not a major source of Hazardous Air Pollutants (HAP) (see Attachment 1); therefore the following MACT subparts are not applicable:

- Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
- Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (this rule was vacated and remanded on July 20, 2007, and was proposed on April 29, 2010)

EPA proposed standards for boilers at area sources of HAPs on April 29, 2010 (40 CFR 63 Subpart JJJJJJ). The proposed rule was published in the Federal Register on June 4, 2010. The requirements for existing boilers (construction/reconstruction commenced prior to the Federal Register publication date) under the proposed rule would apply to Boilers B003 and B004 (125.5 MMBtu/hr and 151 MMBtu/hr, respectively). The definition of "boiler" excludes waste heat boilers, which are defined as follows:

> "Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators."

Therefore, the duct burners (66.6 MMBtu/hr each) may also qualify as existing affected boilers under the rule, depending on the total rated heat input capacity of the Heat Recovery Steam Generators (HRSGs).

Both the duct heaters and the boilers at the facility would be classified in the Oil Subcategory under the proposed rule. The oil subcategory includes "any boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels. Gas boilers that burn liquid fuel during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel are not included in this

[1] See Memorandum from Edward J. Lillis, Permits Program Branch Chief to Bernard E. Turlinski (Region III) and George T. Czerniak (Region V), RE Determining Prevention of Significant Deterioration (PSD) Applicability Thresholds for Gas Turbine Based Facilities, dated February 2, 1993. (http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/turbines.pdf)

definition." Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year (as provided under the gas-fired boiler definition).

Requirements for existing boilers in the Oil Subcategory include:

- CO limit of 2 ppm (3% oxygen)
- Initial stack and subsequent annual stack tests (for boilers less than 100 MMBtu/hr)
- For boilers with heat input capacities greater than 100 MMBtu/hr, a CEMs is required to continuously monitor CO emissions
- Have an energy assessment performed by qualified personnel

These requirements would be become applicable to existing affected boilers 3 years after the date of publication of the final rule in the federal register. Note that gas-fired boilers are not subject to Subpart JJJJJJ. The boilers at the facility could qualify as gas-fired boilers if the permit included limits on fuel oil combustion (only during periods of gas curtailment, gas supply emergencies, or periodic testing not to exceed a combined total of 48 hours per calendar year).

<u>40 CFR 60 Subpart Db – Standards of performance for Industrial-Commercial-Institutional Steam Generating Units</u>

Subpart Db is applicable to steam generating units with heat input capacity greater than 100 MMBtu/hr that are built after June 19, 1984. Boilers B003 and B004 were built in 1958 and 1966, respectively.

<u>40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines</u>

Turbines TU001 and TU002 are subject to Subpart GG. Subpart GG was amended in 2006 to clarify that Excess Emission Reports (EERs) are required semi-annually instead of quarterly (as was incorrectly stated in the previous version of the rule), except during ice fog events. However, it is the Division's current policy to require quarterly EERs; therefore the current quarterly requirement will not be changed.

The facility also has the capability to operate the duct burners without the turbines. In this situation, the Subpart GG requirements do not apply to the duct burners.

<u>SO_2 and Fuel Sulfur Limits for the Turbines – Natural Gas Operation</u>

Subpart GG includes fuel sulfur limits, and Regulations No. 6 and 1 include SO_2 limits (lb/MMBtu) that are applicable to the turbines during both fuel oil and during natural gas combustion. The previous issuance of the permit does not include any of these limits, which were presumably streamlined out due to the more stringent fuel sulfur limit in Condition 1.2. However, this fuel sulfur limit is applicable only to fuel oil, and therefore cannot be used to subsume any limits with respect to natural gas combustion. The following requirements apply to the turbines during natural gas combustion and will be added to the renewal permit:

- Regulation No. 1 – Section VI.B.4.c.(ii) – 0.35 lb SO_2/MMBtu of heat input. Compliance with this requirement shall be presumed, in absence of any credible evidence to the contrary, during periods that only natural gas is used as fuel in the turbine.

- Regulation No. 6, Part B, Section II.D.3.b – 0.35 lb SO_2/MMBtu of heat input. Compliance with this requirement shall be presumed, in absence of any credible evidence to the contrary, during periods that only natural gas is used as fuel in the turbine. This requirement is state-only enforceable. Because this requirement is otherwise identical to the Regulation No. 1 SO_2 limit, it will be streamlined out.

- 40 CFR Subpart GG, Section 60.333(a) & (b) - Sulfur Dioxide (SO_2) emissions from the turbine shall not exceed 150 ppmvd at 15% O2, **or** no fuel, which contains sulfur in excess of 0.8 percent by weight, shall be used in this combustion turbine. Compliance may be demonstrating by showing that the gas burned in the turbines meets the Subpart GG definition of natural gas (20.0 grains or less of total sulfur per 100 standard cubic feet) by completing representative fuel sampling (§60.334(h)(3)(ii)) or by maintaining purchase contracts, tariff sheets or transportation contracts (§60.334(h)(3)(i)).

<u>40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</u>

Duct heaters DU001 and DU002 are subject to Subpart Dc. Note that the requirements apply only to the duct heaters and not to the turbines. Since the previous issuance of the permit on October 1, 2005, Subpart Dc has been amended. The amendments include additional requirements that are applicable to the duct heaters including:

- Submittal of excess emission reports (EERs) with respect to opacity requirements (§60.48c(c)),

- Inclusion of the fuel sulfur content or maximum fuel sulfur content of the fuel oil in the fuel certification (§60.48c(e)(11)(iii)), and

- Opacity monitoring (§60.47c(a)) during operation with fuel oil.

Opacity EERs and the additional fuel certification requirement are incorporated into the renewal permit as described under the discussion of modifications made for the duct burners (see Section III). The opacity monitoring conditions have been updated to reflect the Subpart Dc requirements; see the discussion on opacity requirements below for additional details.

<u>Acid Rain Requirements</u>

On December 10, 2009 the source provided a certified statement that it has not had an agreement to sell electricity since 2006. Therefore, acid rain requirements are not applicable to the turbines at this time (note that under 40 CFR 72.6(b)(4(ii), units selling more than one-third of the potential electrical output capacity to any utility power distribution system are subject to acid rain requirements).

Opacity Requirements

Note that the opacity requirements of Regulation No. 1 are applicable to the turbines, duct heaters and boilers. Subpart Dc also includes opacity requirements applicable to the duct heaters during No. 2 fuel oil combustion. Regulation No. 6 includes opacity requirements applicable to fuel burning equipment constructed, reconstructed or modified after January 30, 1979. Regulation No. 6 requirements apply to the turbines and duct heaters, but not to the boilers which were constructed in 1958 and 1966.

Subpart Dc includes a 20% opacity limit, except for one 6-minute period per hour of not more than 27% opacity (§60.43c(c)). This requirement applies only to the duct heaters, and only when they are burning oil (except not during periods of startup, shutdown or malfunction). The opacity monitoring requirements of Subpart Dc include Method 9 tests on an annual basis, except that more frequent tests are required depending on the results of the previous test. The most frequent test schedule required is once every 30 days. The rule includes an option to use Method 22 tests when the Method 9 tests are below 10%.

The opacity requirements of Regulation No. 1 and Regulation No. 6 are applicable to both the turbines and the duct burners, while operating on natural gas or on No. 2 fuel oil. Regulation No. 1, Section II.A.1 includes a 20% opacity standard that applies at all times except during the following activities: building of a new fire, cleaning of fireboxes, soot blowing, start-up, any process modification or adjustment or occasional cleaning of control equipment. During these specific activities, Regulation No 1, Section II.A.4 requires a 30% opacity limit. Regulation No. 6, Section, Part B, Section II.C.3 also includes a 20% opacity limit; however, this limit applies at all times except during periods of startup, shutdown and malfunction. This means that the Regulation No. 6 limit is more stringent than the 30% limit for all of the listed activities except for startup. However, the Regulation No. 6 limit is State-only enforceable, so it cannot be used to streamline out any of the 30% requirements under Regulation No 1.

Note also that the 20% opacity requirements under Regulations No. 1 and 6 are more stringent than the 27% exception under Subpart Dc. It should also be noted that the Excess Emission Reports (EERs) now required under the amended Subpart Dc are for exceedances of the Subpart Dc opacity standard (i.e., an exceedance of a Regulation No. 1 or No. 6 standard is not necessarily an exceedance of the Subpart Dc standard, due to the 27% exception under Subpart Dc).

The October 1, 2005 issuance of the permit allows that compliance with opacity standards during natural gas combustion may be presumed, in absence of any credible evidence to the contrary. During fuel oil combustion, the permit included the following Method 9 opacity monitoring requirements (applicable to each turbine and to each duct heater):

- To demonstrate compliance with the Regulation No. 1 20% standards during fuel oil combustion:
    - o Within 24 hours of reaching normal operations, once per quarter (not required if startup does not occur during the quarter). Note this condition

applies only during cold startup and not during fuel switching during normal operations.

- If fuel oil is burned continuously for seven days, a visible emissions observation shall be conducted on the seventh day, with subsequent observations taken every seven days thereafter, provided that No. 2 fuel oil is burned continuously.

- To demonstrate compliance with the Regulation No. 1 30% standards:

    - When burning No. 2 fuel oil, compliance with the opacity requirement shall be monitored by conducting visible emissions observations in accordance with EPA Reference Method 9, once per year. This annual observation shall be taken within one (1) hour of the commencement of startup and every 24 hours thereafter until startup is completed. Results of Method 9 readings and a copy of the certified Method 9 reader's certification shall be made available to the Division upon request. A visible emissions observation is not required for any annual period where no fuel oil has been burned. For purposes of this condition, "startup" means a "cold startup" and does not apply to switching fuel during normal operations.

- To demonstrate compliance with the Regulation No. 6, 20% standards: monitoring shall be completed as per the requirements for the Regulation No. 1 20% standards

The following issues are identified with this existing monitoring scenario:

- The requirement to monitor during startup does not demonstrate compliance with any of the listed activities in Regulation No. 1, Section II.A.4 (subject to the 30% limit), except for startup

- The existing monitoring requirements may be less frequent than the schedule required by Subpart Dc for the duct heaters, depending on the results of each individual opacity observation.

- With regard to the "cold startup" language, the Division considers that periods of switching fuel during normal operations likely qualify as process modifications, which would be subject to the 30% opacity standard under Reg 1. Based on the language in the current permit, it is not clear if an opacity reading would ever occur during periods of fuel switching (note that this issue applies to the boilers as well).

Additionally, the specific wording of the Regulation No. 1, 20% opacity requirement in the previous permit suggests that the standard is not applicable during times that the Regulation No. 6, 20% opacity standard applies. As noted above, the Regulation No. 6 opacity rule is State-Only enforceable and therefore cannot be used to replace the federally enforceable Regulation No. 1 requirements.

Because each turbine and duct heater combination share a common stack, any visual opacity observation may be used to demonstrate compliance with all of the opacity requirements for both the turbine and the duct heater (when they are both operating). A new condition (No. 5) has been added to the permit to consolidate all of the monitoring as much as possible and to incorporate the monitoring requirements under the amended Subpart Dc, with the following results:

Turbine and/or Duct Burner Opacity Monitoring Requirements

- Subpart Dc requires visual observations using Method 9 on at least an annual basis, with more frequent subsequent observations (as frequent as every 30 days) depending on the results of the previous test. Although this may result in a frequency that is less than that of the existing permit for Regs 1 and 6 compliance (i.e., quarterly observations, or weekly observations if fuel oil is burned continuously for more than 7 days), the Division believes that the Subpart Dc provisions are adequate to show compliance due to the provisions for increased monitoring based on the results of previous readings.

- Subpart Dc allows an option for replacing Method 9 observations with Method 22 observations under certain conditions. However, Regulation 1 specifies Method 9. Therefore, the permit will not include the option to use the Method 22 observations in order to ensure that monitoring will show compliance with Regulation 1 as well as Subpart Dc (i.e., the Method 22 portions of Subpart Dc are streamlined out).

- The existing permit included a requirement to conduct an annual observation within one hour of commencement of startup and every 24 hours thereafter until startup is completed in order to show compliance with the Regulation No. 1 30% requirement. This condition is still included but is modified slightly to include the other activities subject to the 30% requirement

- A new Appendix G has been added with a recordkeeping format for opacity observations. The purpose is to make it clear and easy to understand how any particular opacity observation will apply to the underlying permit conditions and federal and state requirements by specifying exactly which equipment is in operation (e.g., turbine, duct heater or both), which equipment is operating on fuel oil vs. natural gas, and what activity is being conducted (normal operation, startup, adjustment of control equipment, etc.).

- All of the conditions specifying the actual opacity limits (previous conditions 2.7, 2.8 and 2.9) have been consolidated into a single condition 2.7 for clarity, which also references new Condition No. 5 where opacity monitoring requirements have been consolidated.

Greenhouse Gas Requirements

In 2009 and 2010, EPA issued two rules related to Greenhouse Gasses (GHG) that may affect your facility.

On October 30, 2009, EPA published a rule for the mandatory annual reporting of GHG emissions to EPA from large GHG emissions sources in 40 CFR part 98. You may be required to identify GHG emissions in future Title V permit applications. Such identification may be satisfied by including some or all of the information reported to EPA for meet the GHG reporting requirements.

On May 13, 2010, EPA issued a final rule that sets thresholds for GHG emissions that define when permits under the New Source Review Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. Future new construction and/or modifications at your facility may be subject to PSD review for GHG emissions.

Compliance Status

The Division conducted a full compliance evaluation at the facility on February 26, 2009. The Division's Inspection report notes the following:

- CEMS downtime for the second quarter of 2008 was below 90% due to very low operation of the turbines (9 hours total for turbine 1 and 6 hours total for turbine 2); most of which occurred in startup, shutdown or malfunction mode.
- The November 1, 2008 Excess Emission Report was submitted late on November 4, 2008.

No changes to the permit conditions (with respect to these issues noted in the inspection report) are warranted at this time.

III. Discussion of Modifications Made

Source Requested Modifications

The renewal application received on October 6, 2009 did not request any changes to the existing operating permit. The source submitted a notification (received January 16, 2009) stating that the responsible official had changed. This information was included on the page following the cover page.

Other Modifications

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Power House Operating Permit. These changes are as follows:

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- It should be noted that the monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Modified the language concerning postmarked dates for report submittals to reflect the Division's current standard language.

Section I – General Activities and Summary

- Updated Condition 1.1 to reflect the ozone nonattainment status of the area in which the facility is located
- Revised the language in Condition 1.4 to include current conditions that are state-only enforceable.
- Added a note to Condition 1.5 to state that either electronic or hard copy records are acceptable.
- Updated Condition 3.1 to note that the source is a major stationary source with respect to non attainment new source review requirements (PTE of the Power House and Williams Village combined is greater than 100 tons per year of NO_x). The facility is also major a major stationary source for PSD purposes because CO, NO_x and SO_2 potential to emit exceed 100 tons per year. Note that the previous permit stated a PSD threshold of 250 tpy; this has been corrected to 100 tpy as discussed above in the Applicable Requirements section.
- Condition 6.1 – Relabeled the "Emission Unit Number" column to "Facility Identifier" and removed the previous Facility Identifier column to better reflect the terminology used by the Division and the facility.
- Condition 6.1 – corrected the MMBtu/hr rating for each turbine from 1960 to 189 MMBtu/hr based on information submitted by the source.

Section II – Specific Permit Terms

- Condition 1.1 – This condition has been rewritten and reformatted for clarity. Added a reference to the source of the emission factors listed for the turbines, the duct heaters and the boilers. Corrected the annual PM_{10} equations for the turbines, the duct heaters and the boilers to reference annual fuel use rather than monthly fuel use.
- Condition 1.2 – The condition requiring monitoring of fuel oil sulfur content has been updated to correct regulatory citations from Subpart GG, and to include all of the options allowed under Subpart GG (note that the facility has the option to rely on the sample results of the fuel oil that is delivered as well as sampling from the facility's tanks after each delivery).
- Condition 2 – the interval for the monitoring method listed in the table with respect to the NO_x limit under NSPS Subpart GG has been changed from "Hourly and Monthly" to "Continuously." Although hourly averages are calculated from

the CEMs data, the actual monitoring occurs multiple times per hour in accordance with NSPS requirements (40 CFR §60.13(h)).

- Condition 2.1 – Additional language has been added to the table and to the conditions to clarify that the NSPS standards apply to both simple cycle and combined cycle operation. Note that during combined cycle operation, the standards apply to the combination of each turbine/duct heater. Duct heaters are listed separately under Condition 3 of the permit. Included the averaging time for the NO_x limit in the table at the beginning of Condition 2.

- Condition 2.1.1 – Corrected a typo in the condition language referencing the standard of 75% NOx (the standard is 75 ppmvd, which was shown correctly in the table).

- Previous Condition 2.1.3 included the requirement to install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and ratio of water or steam to fuel being fired in the turbine as a requirement of NSPS Subpart GG. The source conducted the initial compliance test in 1992, during which only one of the units was tested in order to confirm that the CEMS (which is shared by both units) could appropriately monitor and determine compliance with emission limits for both units. A compliance value and/or range for the steam-to-fuel ratio was neither evaluated nor approved because the CEMS monitoring was established as the approved monitoring method.

  Revisions were made to the requirements in NSPS Subpart GG (published in the Federal Register on July 8, 2004 and February 24, 2006) to codify additional monitoring methods that were routinely being approved as alternative monitoring methods, including the option to use a CEMS to establish compliance with NO_x limits.

  Note that the steam-to-fuel ratio is still required as part of the data substitution requirements for the emission calculation methods of Condition 1.1. Other conditions already address the requirements to monitor and record the steam injection rate and fuel consumption rate.Therefore, Condition 2.1.3 will be deleted and subsequent conditions will be renumbered.

- Previous Conditions 2.1.4 through 2.1.8 and 2.2 – These conditions were intended to address Subpart GG monitoring and excess emission reporting (EER) requirements under §60.334. The following issues are identified:

  - Condition 2.1.4 stated that the CEMS required by Condition 1 would be used to monitor compliance with the Subpart GG limit, and included language from §60.334(b)(3)(iii) regarding the relevance of missing data substitution methodology from 40 CFR Part 75, Subpart D. §60.334(b)(3)(iii) applies "if the owner or operator has installed a NO_x CEMS to meet the requirements of Part 75…" which is not the case at this facility (not subject to acid rain requirements).

  - Condition 2.1.5 required the steam-to-fuel ratio to be monitored during the performance test to establish acceptable values and ranges. This was not completed during the initial performance test as described previously.

  In the renewal permit, the monitoring and EER conditions have been replaced with new conditions 2.7 and 6, which are the Division's current standard requirements and format for CEM conditions in operating permits. Note the requirements of the new conditions are the substantively the same as §60.334, except that the Division requires EERs on a quarterly basis instead of a semi-annual basis, which is now allowed under the amended Subpart GG.

- Previous Condition 2.3 (now 2.2) includes the PM standard for fuel burning equipment under Colorado Regulation No. 1. Note that Regulation No.1, Section III.A.1.d, includes the following requirement:

  > "If two (2) or more fuel burning units connect to any opening, the maximum allowable emission rate shall be calculated on a lb/ hour basis as calculated from a weighted average of the individual allowable limits for each unit ducting to the common stack."

  It appears that the previous permit included separate PM emission standards for the duct heaters (Condition 3.3) and the turbines (Condition 2.3). These limits do apply during periods when only the turbines are operational (simple cycle mode), and during periods when only the duct heaters are operational (turbines not operating). However, during the typical operational mode when both the turbines and duct heaters are operational, the applicable limit should be based on a weighted average as per Section III.A.1.d.

  The PM standard for each turbine/duct burner combined is calculated as a weighted average as follows:

$$\mathrm{PE(Combined\ Cycle)} = \frac{\mathrm{PE_T} \times \mathrm{FI_T} + \mathrm{PE_{DB}} \times \mathrm{FI_{DB}}}{\mathrm{FI_T} + \mathrm{FI_T}}$$

  Where $PE_T = 0.5 \times (FI)^{-0.26}$ lb/MMBtu
  $PE_{DB} = 0.5 \times (FI)^{-0.26}$ lb/MMBtu
  FI = Fuel Input in MMBtu/hr

  Note that the original permit specified a fuel input for each turbine of 1960 MMBtu/hr; the source confirmed that this was an error and that actual heat input is 189 MMBtu/hr. Using 189 MMBtu/hr for each turbine and 66.6 MMBtu/hr for each of the duct burners, the combined cycle PM emission standard is 0.1384 lb/MMBtu. Since the PM emission factors for both No. 2 fuel oil and natural gas used to calculate emissions from the duct burners and the turbines (from AP-42, specified in Condition 1.1) are less than the calculated Reg 1 combined cycle standard, compliance with this standard may be presumed since only natural gas and No. 2 fuel oil are permitted as fuels.

The condition has been rewritten to include the correct combined cycle standard and to clarify that separate standards apply during different modes of operation. The table at the beginning of Condition 2 has also been updated accordingly.

- Previous Condition 2.5 (now 2.4) – The fuel consumption limitation condition incorrectly includes a reference to calculations required for excess emission reporting. However, emissions during CEMS downtime or unavailability should not be calculated and reported in EERs; these periods should instead be reported as monitor downtime. The steam-to-fuel ratio data substitution method for calculating emissions relates only to calculating rolling 12-month total emissions under Condition 1.1. This condition has been updated accordingly.

- Previous Condition 2.6 included the General Requirements of 40 CFR Part 60, Subpart A. The Subpart A conditions that are specific to monitoring are now included in Condition 6, which addresses CEMS requirements. Other general conditions from Subpart A have been updated to reflect language changes and moved to a new Condition 7 since they are applicable to the duct heaters as well as the turbines.

- Condition 2.6.10 – this Condition has been updated to reflect the current language of 40 CFR §60.13(h) and has been reformatted for clarity.

- Opacity Conditions (previously Conditions 2.7, 2.8 & 2.9) – The opacity requirements have been rewritten into Condition 2.5 in order to address the issues identified above (see section on Opacity Requirements). Additionally, minor changes to the language related to the presumption of compliance during natural gas firing were made based on comments from EPA on recently issued Operating Permits. A new subcondition is added that defines the duration of an opacity standard exceedance (new condition 2.5.4).

- New Condition 2. 6 – Added the SO_2 and fuel sulfur limits that are applicable to the turbines during natural gas combustion (see discussion in Section II above for additional details). Compliance with the Regulation No. 1 (and the subsumed Regulation No. 6) SO_2 requirements may be presumed during periods of natural gas combustion provided that one of the methods in §60.334(h)(3) is used to demonstrate that the gas burned meets the definition of natural gas in §60.331(u) (periodic sampling or a documentation via a current contract).

- Condition 3.1 – Condition 3.1 has been changed to reference the appropriate Subpart GG conditions from section 2 that also apply to the duct heaters during combined cycle operation.

- Previous Condition 3.2 – Excess Emission Reports related to CEMS are now included in Condition 6, as described previously.

- Previous Condition 3.3 (now Condition 3.2) – the Regulation No. 1 particulate matter limit condition was revised to specify that the limit only applies when the turbines are not in operation (combined cycle limits are addressed under Permit

Condition 2.2), and to include the equation that is used to calculate the appropriate limit. The table at the beginning of Condition 3 has been updated accordingly.

- Previous Condition 3.4 (now Condition 3.3) – The condition limiting fuel use for the duct heaters included a statement that fuel consumption should be used to calculate emissions as required by the conditions related to Subpart GG monitoring and EERs. Since the facility uses the CEMs to demonstrate compliance with Subpart GG, this statement has been removed. However, fuel use is used to calculate emissions from the duct heaters for pollutants not measured by the CEMS (as described in Condition 1.1), and in the data substitution requirements of Condition 1.1. Therefore, this condition has been updated to reference the emission calculation requirements of Condition 1.1. The table at the beginning of Condition 3 previously stated that the fuel limit applied to the heaters separately; this has been corrected – the limit applies to both heaters combined.

- Previous Condition 3.5 – Since the previous issuance of the permit, NSPS Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) has been amended. Section II of this document includes discussion of the changes to the rule with respect to the duct heaters. Requirements to include the fuel sulfur content fuel certification were added to the semiannual reporting condition to address the Subpart Dc amendments. A new condition (3.5.4) has been added to address the Excess Emission Report (EER) requirement with respect to opacity standards under Subpart Dc. The opacity requirements with respect to Subpart Dc have been consolidated into a separate condition No. 5 (see discussion related to opacity requirements, above).

- Previous Condition 3.6 – 40 CFR Part 60, subpart A requirements have been moved to new condition 7 as described previously.

- Opacity Conditions (previously Conditions 3.7, 3.8 & 3.9) – The opacity requirements from Regulations No. 1 and 6 have been rewritten into Condition 3.4 (the Subpart Dc opacity requirements are included in Condition 3.5). The new opacity requirements are designed to address the issues identified above (See Section II for further details). Additionally, minor changes to the language related to the presumption of compliance during natural gas firing were made based on comments from EPA on recently issued Operating Permits. A new subcondition is added that defines the duration of an opacity standard exceedance (new condition 3.4.4).

- Boilers B003 and B004: In the October 1, 2005 issuance of the permit, the boilers are separated into two different conditions, even though all requirements are identical for each boiler and the fuel limit applies to both boilers together rather than individually. The boilers have slightly different heat inputs (125.5 MMBtu/hr and 151 MMBtu/hr); however the particulate matter equation of Regulation No. 1, Section III.A.1.b provides the same PM limit for each boiler within two decimal digits. The renewal permit will combine both boilers into a single set of conditions to remove redundancy and to help clarify the combined fuel limitation. The following additional revisions were made to the boiler conditions:

- o Minor changes were made to the language regarding presumption of compliance with the standards based on recent comments EPA has made on other operating permits. Compliance may be presumed (in absence of any credible evidence to the contrary) because the emission factors for the boilers (0.0076 lb/MMBtu for natural gas and 0.0236 lb/MMBtu for No. 2 fuel oil) are less than the Reg 1 particulate standard of 0.14 lb/MMBtu.

- o The opacity conditions have been reformatted to be similar to those for the turbines and duct heaters. The language related to presumption of compliance with the standard during natural gas operation has been modified slightly based on recent comments from EPA on other operating permits. The October 1, 2005 permit required opacity monitoring during startup to show compliance with the Regulation No. 1, 30% opacity requirements, but not during any of the other activities specifically listed in Regulation No. 1, Section II.A.4. The monitoring condition has been modified to include any of the listed activities. A new subcondition is added that defines the duration of an opacity standard exceedance (new condition 4.3.3). The new condition 5 and Appendix G have been updated to address boilers, similar to the turbines/duct heaters.

<u>Section III – Permit Shield & Streamlined Conditions</u>

- Corrected the regulatory citation at the beginning of the permit shield section

- Reformatted the streamlined conditions table to the Division's current standard

- Note that the previous permit incorrectly streamlined out Subpart GG, Regulation No. 6 and Regulation No. 1 SO_2 standards for the turbines during natural gas combustion (as described previously). The streamlined conditions listings have been re-written to clarify that they are only applicable to fuel oil combustion in the turbines. The Regulation No. 6 SO_2 Standard can now be streamlined out in favor of the Regulation No. 1 SO_2 standard.

- The reference to §60.46c has been removed from the streamlined conditions table; §60.46c does not have any applicable requirements for facilities that demonstrate compliance with the SO_2 standards based on fuel supplier certification.

- Since the previous issuance of the operating permit, Subpart Dc has been amended to require opacity monitoring during fuel oil combustion for the duct burners. Therefore, opacity monitoring for the duct heaters is no longer listed as a subsumed condition in the streamlined conditions table.

- Subpart Dc includes requirements to maintain records of the amount of fuel combusted during each calendar month that are applicable to the duct heaters

(§60.48c(g)(2)). This requirement is subsumed by the requirement in the existing permit to monitor fuel use every hour and maintain 12 month rolling totals. These requirements were included in a new entry in the streamlined conditions table.

- The options to use Method 22 in lieu of Method 9 opacity observations under some circumstances for the duct burners under Subpart Dc has been streamlined out in favor of the Method 9 readings since the same monitoring will be used to demonstrate compliance with the opacity standards of Regulations No. 1 and 6. The streamlined conditions table has been updated accordingly.
- Regulation No 6, Part B, Section II.C.2 (State-only enforceable) includes PM standards for the turbines and duct heaters that are identical to the Regulation 1 PM standards in Section II, Conditions 2 and 3. The Regulation 6 requirement has been added to the table of streamlined requirements.
- Excess Emission Reporting for NO_x under Subpart GG (§60.334(j)(1)(iii)) is now streamlined in favor of the Division CEMS requirements.

Section IV – General Permit Conditions

- Updated the general permit conditions to the current version (7/21/2009).

Appendices

- Updated Appendix A to include a note that the fuel oil storage tanks qualify as insignificant activities based on an annual throughput less than 400,000 gallons, as per Regulation No. 3, Part C, Section II.E.3.fff.(ii)(B). The permitted throughput for the turbines is higher than this exemption level; therefore records should be kept to verify that the exemption threshold is not exceeded.
- Updated Appendices B and C (Monitoring and Permit Deviation Reports and Compliance Certification Reports) to the newest versions (2/20/2007).
- EPA's mailing address was revised (Appendix D).

IV. Comments received during Public Notice Period

The source submitted comments on July 21, 2010 noting that the section titled "Compliance Status" in this technical review document included language that could be interpreted to mean that the NSPS GG NO_x limit applies during periods of Startup, Shutdown or Malfunction events. The Division revised the section accordingly.

ATTACHMENT 1 – FACILITY EMISSION CALCULATIONS

Potential to Emit: HAPs for TU001 & TU002 (combined)

	Emission Factor (lb/MMBtu)[1]		Emissions based on Permitted Fuel Use[2]		Max PTE[3]
Pollutant	**Natural Gas**	**Distillate Oil**	**Natural Gas**	**Distillate Oil**	**lb/yr**
Lead		1.40E-05	0	3	3
Acetaldehyde	4.00E-05		111	0	111
Formaldehyde	7.10E-04	2.80E-04	1970	52	2023
Propylene Oxide	2.90E-05		80	0	80
Manganese		7.90E-04	0	148	148
TOTAL					**2365**

Notes

1. Emission factors are from AP42, Chapter 3.1 (4/2000)
2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (2775 MMscf/year for natural gas, 1,430,000 gal/year for oil). Fuel heat values are assumed to be 1,000 btu/scf for natural gas and 130,854 btu/gal for fuel oil, based on values submitted on APENs received on 12/10/2009
3. PTE is the total emissions from both permitted fuels. HAPs included in the table above are those where Max PTE exceeds APEN reportable thresholds.

Potential to Emit: HAPs for DU001 & DU002 (combined)

	Emission Factor[1]		Emissions based on Permitted Fuel Use[2]		Max PTE[3]
Pollutant	**Natural Gas (lb/MMscf)**	**Distillate Oil (lb/Mgal)**	**Natural Gas**	**Distillate Oil**	**lb/yr**
Lead	0.0005		0	0	0
Benzene	2.10E-03	2.14E-04	1	0	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	30	10	40
Naphthalene	6.10E-04	1.13E-03	0	0	1
Toluene	3.40E-03	6.20E-03	1	2	3
Xylenes		1.09E-04	0	0	0
TOTAL					44

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) and 1.4 (7/1998).
2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (400 MMscf/year for natural gas, 288,000 gal/year for oil).
3. PTE is the total emissions from both permitted fuels. Note that no HAPs exceed APEN reportable thresholds at the permitted fuel limits.

Potential to Emit: HAPs for B003 & B004 (combined)

Pollutant	Emission Factor[1]		Emissions based on Permitted Fuel Use[2]		Max PTE[3]
	Natural Gas (lb/MMscf)	Distillate Oil (lb/Mgal)	Natural Gas	Distillate Oil	lb/yr
Lead	0.0005		0	0	0
Benzene	2.10E-03	2.14E-04	1	0	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	50	6	56
Naphthalene	6.10E-04	1.13E-03	0	0	1
Toluene	3.40E-03	6.20E-03	2	1	3
Xylenes		1.09E-04	0	0	0
TOTAL					62

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) and 1.4 (7/1998).

2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (660 MMscf/year for natural gas, 193,000 gal/year for oil).

3. PTE is the total emissions from both permitted fuels. Note that only formaldehyde exceeds APEN reportable threholds at the permitted fuel limits.

Power House Facility-Wide Potential to Emit (HAPs)

	Formaldehyde[1] (tons/year)	Total HAP[2] (tons/yr)
TU001 & TU002	1.01	1.18
DU001 & DU002	NA	NA
B003 & B004	0.03	0.03
TOTAL	**1.04**	**1.21**

Notes

1. Highest Single HAP

2. HAPs included for each point are those where emissions at the maximum permitted fuel use exceed APEN reportable thresholds.

Potential to Emit: B001 & B002 (both Williams Village Boilers combined)

	Emission Factor[1]		Emissions based on Max Assumed Fuel Use[2]		Max PTE[3]
Pollutant	**Natural Gas (lb/MMscf)**	**Distillate Oil (lb/Mgal)**	**Natural Gas**	**Distillate Oil**	**ton/ytr**
CO	84	5	27.8	12.8	27.8
VOC	5.5	0.2	1.8	0.5	1.8
PM	7.6	3.3	2.5	8.5	8.5
PM10	7.6	1.65	2.5	4.2	4.2
NOx					43.0
SO2					47.0

HAP Potential to Emit: B001 & B002 (both Williams Village Boilers combined)

	Emission Factor[1]		Emissions based on Max Assumed Fuel Use[2]		Max PTE[3]
Pollutant	**Natural Gas (lb/MMscf)**	**Distillate Oil (lb/Mgal)**	**Natural Gas**	**Distillate Oil**	**lb/yr**
Benzene	2.10E-03	2.14E-04	1	1	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	50	169	169
Naphthalene	6.10E-04	1.13E-03	0	6	6
Toluene	3.40E-03	6.20E-03	2	32	32
Xylenes		1.09E-04	0	1	1
TOTAL					**209**

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) for fuel oil combustion, and 1.4 (7/1998) for natural gas combustion. PM10 emissions from distillate oil are assumed to be 50% of PM based on AP42 Table 1.3-6.
2. Emissions for each fuel type are calculated based on an assumed maximum fuel consumption (i.e., combined boiler heat input of 77 MMBtu/hr, and assuming a natural gas heat value of 1020 btu/scf and a fuel oil heating value of 131,622 btu/gal (from the APEN received on 3/29/2007), and assuming operation of 8760 hours per year on each fuel type.

3. PTE is assumed to be the higher of the values calculated for each fuel type (except for NOx and SO2, which are the permitted limits). Note that only formaldehyde exceeds APEN reportable thresholds at the Maximum Assumed Fuel Use.

Potential to Emit: Williams Village & Power House Combined

Pollutant	Power House[2]	Williams Village[3]	TOTAL
NOx	Less than 250	43.0	Less than 293
CO	90	27.8	117.8
VOC	62.6	1.8	64.4
SO2	56.7	47.0	103.7
PM	24.2	8.5	32.7
PM10	24.2	4.2	28.4
Formaldehyde[1]	1.04	0.1	1.1
Total HAPs	1.21	0.1	1.3

Notes

1. Highest Single HAP

2. PTE for criteria pollutants are based on permit limits (PM10 is assumed to be equal to PM). See detail for Power House emission units for HAP PTE calculations

3. See detail for Williams Village Boilers for HAP and Criteria PTE calculations

ATTACHMENT 2 – RULE VERSION DATES

This Technical Review Document considers applicability and requirements from rules and regulations at the time the renewal permit was drafted. The version dates of these rules and regulations are listed in the following table:

Rule/Regulation	**Version Date**
Colorado Regulation No. 1	Amended 6/21/07, effective 8/30/07
Colorado Regulation No. 6	Amended 6/18/09, effective 7/30/09
40 CFR 63 Subpart YYYY	April 20, 2006
40 CFR 63 Subpart DDDDD	Proposed April 29, 2010
40 CFR 63 Subpart JJJJJJ	Proposed April 29, 2010
40 CFR 60 Subpart GG	February 24, 2006
40 CFR 60 Subpart Dc	January 28, 2009